

Assessment of the integration of CO₂ capture technology into oil–sand extraction operations

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Abstract The deployment of CO₂ capture and storage technologies in oil sands operations exhibits an outstanding potential to reduce CO₂ emissions, out of the ones produced by power generation sector. This paper assesses through thermodynamic modeling the influence of integrating CO₂ capture technologies into two different configurations for in situ bitumen extraction plant (SAGD) reference cases. Results from this analysis will allow putting forward the optimum option in terms of energy and CO₂ emissions reduction. Unlike the extensively explored CO₂ capture in fossil fuel power plants, evaluation addressed in this study, within the scope of energy penalty and CO₂ avoided, reveals a clear advantage of oxy-fuel combustion.

Keywords SAGD · CO₂ capture · Oxy-fuel · Post-combustion · Oil–sands

Abbreviations

SAGD	Steam assisted gravity drainage
ASU	Air separation unit
CPU	CO ₂ processing unit
GT	Gas turbine
HRSG	Heat recovery steam generator
<i>m</i>	Mass flow (kg/s)
RFG	Recycled flue gas
SG	Steam generator

SOR	Steam to oil ratio
<i>T</i> _{max}	Temperature of the combustion chamber
<i>W</i>	Electrical power (MW)

Highlights

- A quantitative assessment evaluates the impact of CO₂ capture in SAGD operation.
- Two approaches are considered in the evaluation: energy and CO₂ emissions.
- Oxy-fuel combustion in SAGD is optimum technology in terms of energy and avoided CO₂.

Introduction

The Canadian oil sands are currently ranked third in proven crude oil reserves in the world with 171.3 billion barrels of oil, from which 169.9 billion barrels consist of bitumen (unconventional oil) and 1.4 billion barrels are conventional oil [1]. The bitumen is similar to crude oil but denser, more viscous, with an average composition of 83.2 % carbon, 10.4 % hydrogen, 0.94 % oxygen, 0.36 % nitrogen, and 4.8 % sulfur [2]. Bitumen in the Canadian oil sands is present in high enough concentration to make its extraction and conversion into synthetic crude oil economically feasible at current oil prices. Hence, bitumen extraction rate has increased in the last decade at the same time that it has become a strong competitor against oil. The latest estimate from the Canadian National Energy Board anticipates that by 2030, daily oil sands production could reach nearly 5 million barrels. Production at 2009 was approximately 1.2 million barrels of bitumen and synthetic crude oil [3].

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The overall oil sand operations process to produce synthetic oil accounts for two main stages: the extraction and the upgrading [4]. About 80 % of the oil sands resources need to be extracted with in situ methods [1], among which the most used is the steam assisted gravity drainage (SAGD). SAGD operations consist of pairs of wells vertically aligned and horizontally drilled. Hot steam is pumped into the upper injection well, and is used to heat up the surrounding oil sands. As the bitumen temperature increases, it falls away from the sand and clay, and gradually filters down to the lower production well. The bitumen and water are pumped back to the surface from the production well [4]. SAGD energy requirements are entirely produced using fossil fuels, mainly natural gas, which inevitably results in significant CO₂ atmospheric emissions [5].

In 2008, reported greenhouse gas emissions (GHG) in Canada from large industrial facilities were 262.6 Mt [6]. Alberta, the richest region in oil sands of Canada, was the largest provincial contributor with 42 % of the total. In Alberta, oil sands operations emit roughly 35 Mt of GHG (96.4 % corresponds to CO₂ emissions), representing almost a third of the total emissions in the province [6]. In the future the oil sands sector may overtake electricity as Alberta's leading source of emissions [7]. According to the Canada's climate change action plan [8], the objective for 2020 is to reduce industrial greenhouse gas emissions 150 Mt, or roughly 20 % reduction compared to national 2006 levels [9]. The politics addressing this goal must involve CO₂ capture and storage technologies as one of the main pillars to accomplish that greenhouse gas emission reduction. The four groups of technologies technically feasible to capture CO₂ from the stationary combustion sources in the mid-term are generally classified in pre-combustion, post-combustion, oxy-fuel combustion and chemical looping combustion technologies [10, 11].

A previous study [12], which assessed the qualitative integration of the capture of CO₂ from the oil sand operation processes, proposed oxy-fuel combustion and post-combustion technologies, as the most suitable ones to be accomplished into a SAGD extraction system. On the one hand, oxy-fuel combustion could be feasibly applied to large-scale boilers and, furthermore, it allows either retrofitting or replacing the existing boilers. Post-combustion capture seemed less attractive since it involves large steam requirements for the sorbent regeneration. Still, post-combustion using amine chemical absorption is one of the most mature and known technologies for CO₂ capture. Pre-combustion technology presented highlighted advantages to be integrated into the upgrading stage, by gasifying bitumen residues and coal blends to produce H₂. But for the steam generation in a SAGD process, it would require extra equipment downstream to capture CO₂, and the

replacement of the steam generation arrangement. Regarding chemical looping combustion technology, in spite of offering remarkable advantages over other capture technologies, the degree of development is still at non-commercial scale, and its deployment at great scale implies considerable uncertainty.

This paper intends to mean a step forward in the evaluation of the suitable CO₂ capture technology when integrated into SAGD operations. From two reference SAGD commercial scale plants, the deployment of CO₂ capture by oxy-fuel combustion and by post-combustion approaches will be quantitatively compared, in terms of energy and emissions performance. This paper pursues to establish the optimum CO₂ capture technology for each plant layout, if possible.

Cases of study

SAGD reference cases

A SAGD plant requires large amounts of steam and electricity for its operation. The rate of bitumen extracted sets the thermal and electric needs of the plant. A typical value of SAGD electricity consumption is 3.4 kWh/bbl [13]. Regarding the steam, the parameter that defines the demand is the so-called steam to oil ratio (SOR), which represents the number of barrels of steam required to extract a single barrel of bitumen. Injected steam conditions are typically at 80 bar and 300 °C [5]. To meet these energy demands several cogeneration configurations are possible. If a gas turbine is sized to provide the SAGD requirements, the thermal energy of the flue gasses are not enough to satisfy the steam demand and thus, an additional steam generator is needed. If, on the other hand, the extra steam generator is avoided, and steam is generated exclusively in the heat recovery steam generator (HRSG), the gas turbine will have to be larger and it will generate surplus of electricity that should be sold to the grid.

A recent survey [14] establishes the delivered price of power versus cost of generation, the reliability of power from the grid and the balance of load and cogeneration as the main factors which influence the decision to invest in cogeneration. Currently, about 40 % of the total projects have selected on-site cogeneration. The same survey reports that in the late 2000s, the transmission capacity of Alberta's grid was limited, and the power pool prices were volatile. Therefore, oil sands developers have tended to size their cogeneration projects close to on-site conditions, lowering the forecasted net exports to the grid. However, looking forward, the Alberta electric power systems operator (AESO) is planning to build two new 500 kV transmission lines, so oil sands developers will consider to



oversize the cogeneration capacity and export electricity to the grid [14].

Within this context, the two cogeneration arrangements will be considered as reference case for the integration of the CO₂ capture train. The reference case A will assume that the gas turbine provides the electricity required by the SAGD process. The reference case B will regard the configuration in which the gas turbine produces excess of electricity that will be derived to the grid.

Case A: gas-turbine sized for on-site requirements

The flow-sheet of the reference case A is represented in Fig. 1. In this configuration, the electricity required during the plant operation is provided by the natural gas turbine, sized to cover the plant self-demand. The gas turbine is coupled with a HRSG that makes use of the exhaust gasses energy to produce part of the steam needed in the SAGD operations. Flue gas temperature leaves the HRSG at 120 °C and the gasses are released to the environment. To complete the steam rate needed in the process, an additional natural gas boiler must be included. The mixture of condensed steam and bitumen obtained from the production well is the final output of the process boundary considered in this study. The main parameters for the reference case are summarized in Table 1.

Case B: excess of produced electricity to the grid

In the reference case B the steam required by the SAGD process is entirely produced in the HRSG, and thus, the gas turbine must be larger than required by the process alone. The excess of electricity is transferred to the grid. The flow-sheet is shown in Fig. 2. The boiler present in the previous configuration is not required in this case. The

parameters summarized in Table 1 are considered now as well, hence, the electricity and the steam required by the overall process remain the same.

SAGD with CO₂ capture

The main CO₂ emission sources in a SAGD plant are located in the stack. This makes CO₂ capture system simpler to be integrated in a SAGD process, unlike the subsequent upgrading stage, which involves complex processes with numerous CO₂ emission sources.

The two most convenient technologies [12] to capture CO₂ from SAGD will be ponder. Additionally, the separated CO₂ must be compressed up to 100 bar in the CO₂ processing unit (CPU) to be further transported to the storage site. Compression stage plays also a relevant role in the evaluation of the energy demands of the overall process and it will be included in the analysis. The electric consumption considered is 100 kWh/tCO₂ [13].

SAGD with post-combustion CO₂ capture

Post-combustion capture is the removal of CO₂ from flue gasses downstream of the emission sources. The system involves liquid absorption using chemical solvents. Amine-based solvents are the most mature ones, although the high degradation rate of the amines and the thermal energy for the solvent regeneration, imply the main drawbacks of this technology. A common value of the energy demand in commercial amine-solvents is 4 GJ/tCO₂ [17], which is provided by the condensation of steam in the regeneration tower reboiler. A typical value of temperature of steam is around 130 °C. CO₂ recovery efficiency of post-combustion capture varies from 85 to 95 %.

Fig. 1 SAGD reference case A

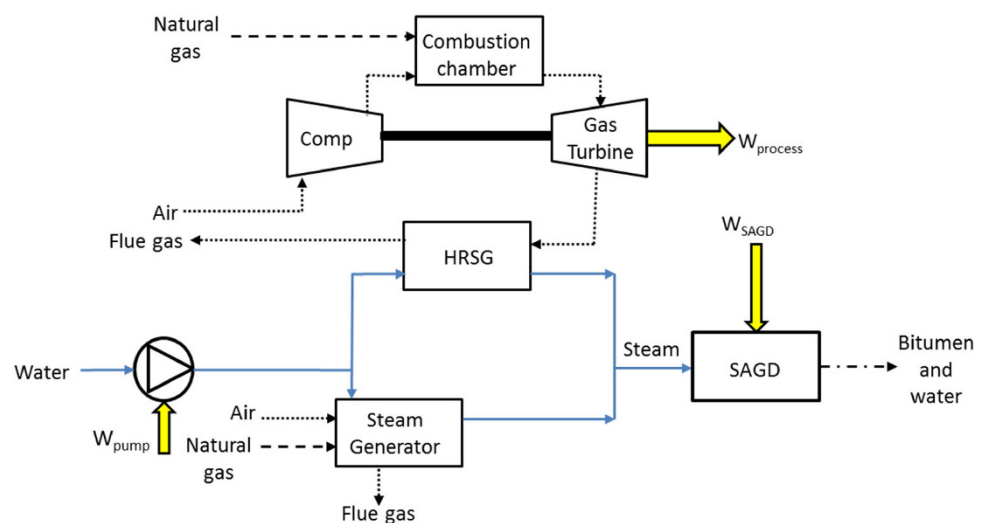


Table 1 Reference SAGD main parameters [2, 5, 13]

Parameter	Value	Units
Bitumen extraction rate	100,000	bbl/d
SAGD electricity consumption	3.4	kWh/bbl
SOR	3	–
SAGD steam conditions	80/300	bar/°C
Gas turbine efficiency	34	%
Gas turbine T_{\max}	1,300	°C
HRSG effectiveness	95	%
Steam generator efficiency	90	%
Steam generator excess air	5	%

The resulting flow-sheet of integrating post-combustion CO_2 capture with the SAGD on-site requirements plant is represented in Fig. 3. In the plant there are two major CO_2 sources: the HRSG and the boiler. Both are mixed and cooled down before entering the absorption tower. The solvent absorbs the CO_2 from the exhaust gas and leaves the tower from the bottom stage in liquid phase (rich amine). The N_2 and other compounds abandon the absorption tower and are released to the environment. The regeneration of the rich amine takes place in a second tower, requiring considerable quantity of thermal energy. This heat is provided through the reboiler by the supply of steam from the boiler. The regenerated solvent is recycled back to the absorption tower. After removing the water by condensation, a high CO_2 concentration stream is obtained. The stream reaches the optimal conditions in the CPU for transportation.

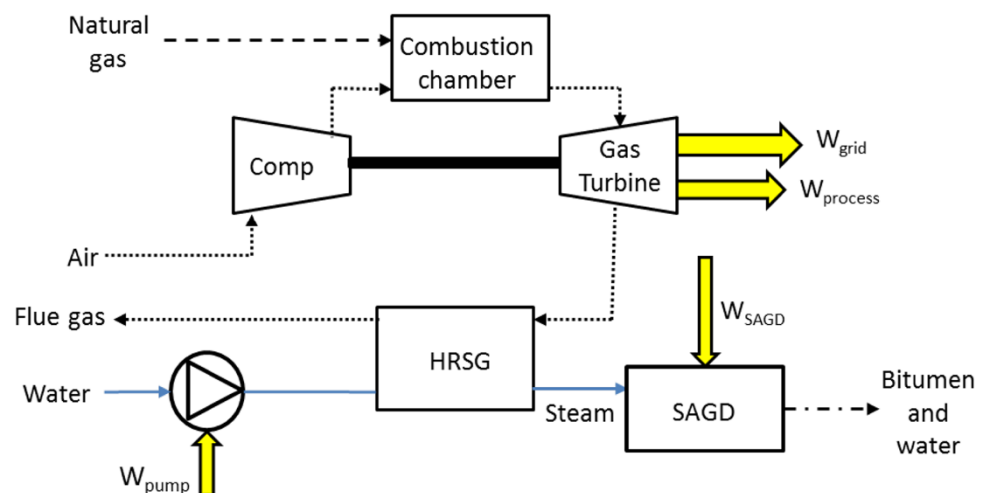
The flow-sheet of the SAGD case B with post-combustion CO_2 capture is schematized in Fig. 4. The flow-sheet description is analogous to the previous, except that there is not a boiler and the steam for the reboiler is also produced in the HRSG.

SAGD with oxy-fuel CO_2 capture

In oxy-fuel combustion, pure oxygen is used as oxidant instead of air. Thereby, the resulting flue-gas stream consists mainly of CO_2 and steam. The steam can be removed by condensation, and CO_2 is then recovered at high concentrations. Adopting an oxy-fuel combustion system implies two main changes in a SAGD plant. On the one hand, the oxygen rate for combustion is provided by an air separation unit (ASU). At commercial scale, the cryogenic technology is used in ASU plants, with the associated electricity demand. A common value considered for estimating the electricity demand is 0.2 kWh/kg of produced O_2 [15]. On the other hand, in order to moderate the combustion temperature, the fed oxygen must be diluted in recycled flue gas (RFG) stream. Thus, part of exhaust gases, mainly composed of CO_2 , is fed back into the combustion chamber. The percentage of RFG necessary to keep the materials within a safety conditions is high, around 90 % [18]. The natural gas boiler will also work under oxy-fuel conditions. Its performance will be assimilated to the research pilot plant operating in Lacq (France). The flue gasses temperature at the outlet of Lacq's steam generator is 220 °C [19]. This temperature will also be considered here.

Figure 5 shows the schematic flow-sheet of oxy-fuel CO_2 capture into the SAGD reference case A. Analogously, mass and energy flows are indicated in the diagram. The CO_2 emitting sources are again the HRSG and the steam generator. Before entering the CPU, the streams are mixed and dried, and at the CPU's outlet the CO_2 is ready for its transport.

The flow-sheet representing the integration of oxy-fuel CO_2 capture in the reference case B SAGD process is shown in Fig. 6. The natural boiler is not needed here and excess of produced electricity is conveyed to the general net.

Fig. 2 SAGD reference case B

The diagram illustrates a complex industrial process involving energy conversion and CO₂ capture. At the top, 'Natural gas' (dashed line) and 'Air' (dotted line) enter a 'Combustion chamber'. The output of the combustion chamber goes to a 'Gas Turbine', which produces 'W_{process}' (yellow arrow). The 'Gas Turbine' is connected to a 'Comp' (compressor). The 'Comp' also receives 'Air' (dotted line). The 'Gas Turbine' exhausts 'Flue gas' (dotted line) into an 'HRSG' (Heat Recovery Steam Generator). The 'HRSG' also receives 'Flue gas' (dotted line) from the 'Combustion chamber'. The 'HRSG' produces 'Steam' (blue arrow) which goes to a 'SAGD' (Steam Assisted Gravity Drainage) unit. The 'SAGD' unit receives 'W_{SAGD}' (yellow arrow) and 'Steam' (blue arrow). The 'SAGD' unit produces 'Bitumen and water' (dotted line). The 'SAGD' unit also receives 'N₂, Ar...' (dotted line). The 'SAGD' unit exhausts 'Flue gas' (dotted line) into a 'Reboiler cycle'. The 'Reboiler cycle' consists of an 'Abs' (Absorber) and a 'Reg' (Regenerator). The 'Reboiler cycle' also receives 'Flue gas' (dotted line) from the 'HRSG'. The 'Reboiler cycle' produces 'CO₂' (blue arrow) which goes to a 'CPU' (CO₂ Purification Unit). The 'CPU' produces 'CO₂ Transport' (dotted line). The 'CPU' also receives 'W_{CPU}' (yellow arrow). The 'CPU' unit is connected to a 'Flue gas mixture' (dotted line) which enters the 'Abs' of the 'Reboiler cycle'. The 'Reboiler cycle' also receives 'Air' (dotted line) and 'Natural gas' (dashed line) into the 'Steam Generator'. The 'Steam Generator' produces 'Steam' (blue arrow) which goes to the 'SAGD' unit. The 'Steam Generator' also receives 'Flue gas' (dotted line) from the 'Reboiler cycle'. The 'Steam Generator' is connected to a 'Water' pump (blue arrow) which produces 'W_{pump}' (yellow arrow). The 'Water' pump also receives 'Water' (blue arrow). The 'Water' pump exhausts 'Water' (blue arrow) into the 'SAGD' unit. The 'Water' pump also receives 'Flue gas' (dotted line) from the 'HRSG'.

The diagram illustrates a process flow for CO₂ capture and utilization. Key components and flows include:

- Gas Turbine Cycle:** Natural gas and Air enter a Combustion chamber. The chamber feeds a Compressor (Comp) and a Gas Turbine. The Gas Turbine produces work W_{grid} and $W_{process}$. Exhaust from the Gas Turbine goes to the HRSG.
- Water and Steam Cycle:** Water is pumped (W_{pump}) into the HRSG. The HRSG produces Steam, which is fed into the SAGD unit. Exhaust from the SAGD unit is Bitumen and water.
- CO₂ Capture and Utilization:** Exhaust from the HRSG enters a Reboiler cycle, which feeds into an Absorption (Abs) and Regeneration (Reg) system. The Abs system uses Rich solvent, and the Reg system uses Poor solvent. The Reg system produces CO₂, which is fed into a CO₂ Purification Unit (CPU). The CPU also receives W_{CPU} and produces CO₂ Transport. Exhaust from the CPU goes to the HRSG.
- Flue Gas and Nitrogen/Argon:** Flue gas enters the Abs system. Nitrogen and Argon ($N_2, Ar...$) are also fed into the Abs system.

systems, similarly as in refs. [10, 20], taking into consideration the initial parameters shown above.

The two different approaches for SAGD reference configurations will be separately assessed. All the analysis'

Fig. 5 SAGD case A with integrated oxy-fuel CO_2 capture

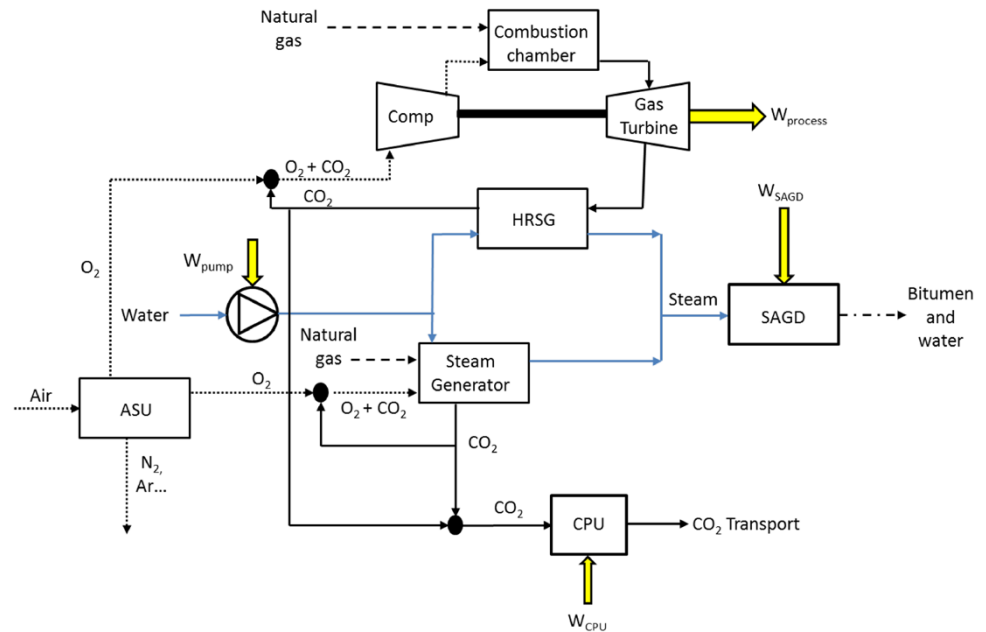
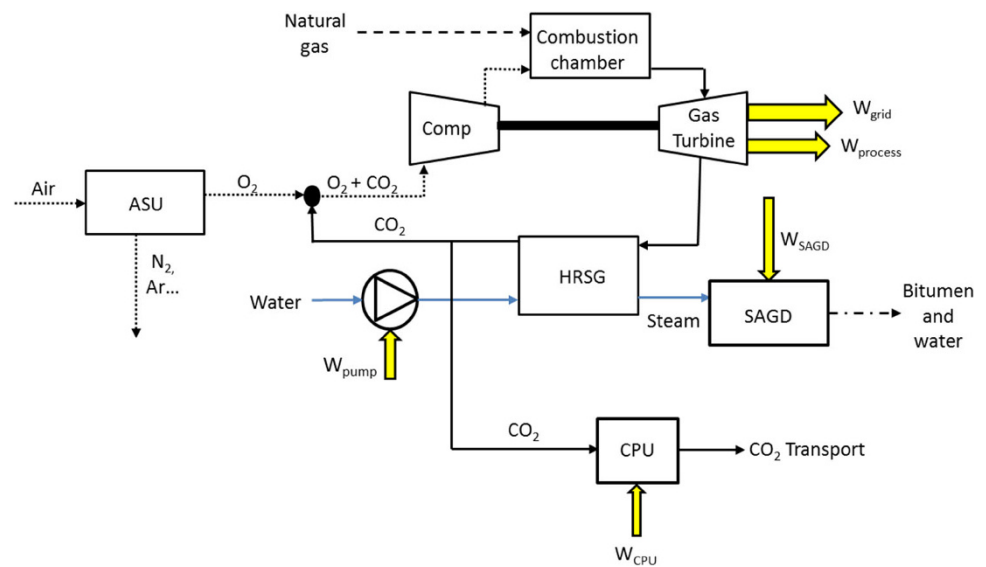


Fig. 6 SAGD case B with integrated oxy-fuel CO_2 capture



are carried out in the basis on the 100,000 bbl/d of bitumen production rate. The gas turbine in the case A approach would produce the electricity demanded by a plant of that size. In case of including any of the CO_2 capture technologies, post-combustion or oxy-fuel, the increase of electricity demand would need the higher output in the gas turbine. Steam generated by the HRSG would increase correspondingly. Complementary steam would be generated in an additional boiler. On the other hand, the case B approach would produce all the steam required by the process in the HRSG. Thus, the size of the gas turbine ought to increase 1.8 times, as it will be following explained.

CO_2 capture evaluation in the case A SAGD configuration

The results of the main energy-related parameters of the reference case A are summarized in Table 2. The three situations are presented indicating the power produced in the gas turbine (GT), and the steam generated both, in the HRSG and in the steam generator (SG).

The initial condition of this configuration resides on the self-demand electricity supply. Thus, the increase of power requirement when CO_2 capture is included, allows higher steam generation in the HRSG, saving fuel in the natural gas boiler. The post-combustion CO_2 capture requires

Table 2 Main results of integrating CO₂ capture into the reference case A of SAGD process

Parameter	SAGD no capture	SAGD with post-combustion	SAGD with oxy-fuel
W_{GT} (MW)	14.35	16.20	21.02
Q_{HRSG} (MW _t)	21.93	24.75	32.78
Q_{SG} (MW _t)	38.87	56.62	28.02
W/Q_{fuel}	0.17	0.15	0.23
m_{fuel} (m ³ N/s)	2.25	2.91	2.45
m_{CO_2} (kg/s)	4.41	0.57	0.48

9.47 kg/s of steam, which represents 29 % of the total amount produced. This leads to an increase of 46 % of thermal energy supplied by the boiler.

When including oxy-fuel combustion into the SAGD configuration, the electricity demanded by the ASU and CPU leads to an increase of GT output of 46.5 %. This enlargement enables the HRSG to generate higher steam rate and thus, save fuel in the natural gas boiler. The cost in terms of fuel is only 9 % higher than the reference case. This also leads to an increase in the ratio between the power generation and the fuel input. This parameter must be carefully considered, not forgetting that the higher fuel supply leads to an unavoidable energy penalty compared with the reference case.

Notice that the oxy-fuel combustion requires RFG stream to dilute the oxidant and to control the temperatures in the combustion chamber and in the boiler. The percentage of RFG resulted 95.3 % in the oxy-fuel gas turbine and 88.3 % in the oxy-fuel natural gas steam generator. The O₂ concentration at the inlet turned out 10.9 % in the gas turbine and 24.5 % in the steam generator.

Still, in terms of energy, and leaving from the assumption of self-generation plant, the oxy-fuel configuration for capturing CO₂ from SAGD process appears as the favorable configuration, compared to that of the post-combustion capture.

The reduction of CO₂ emissions from an existing process must be analyzed in terms of avoided CO₂ emissions. This term accounts for the increase of CO₂ emissions due to the incorporation of the CO₂ capture system, with the associated increase in fuel feeding rate. In Fig. 7, results of the avoided CO₂ emissions in the three configurations are represented, in order to perceive the real scope of CO₂ reduction in every situation.

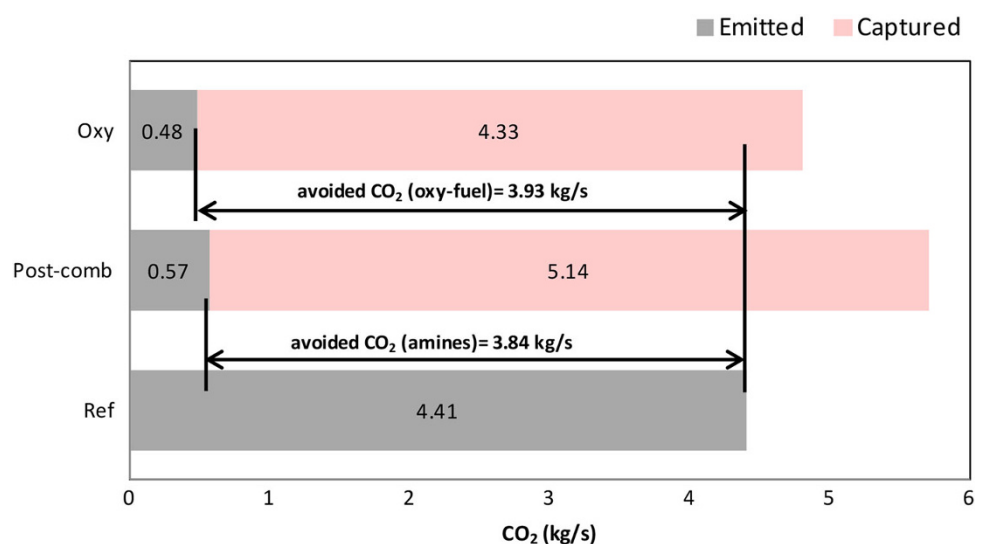
By including post-combustion and oxy-fuel capture into the SAGD system, CO₂ emissions would be 29 and 9 % higher than in the reference case A, respectively.

The evaluation of CO₂ emissions entails uncertainties, due to the value of CO₂ capture efficiency. In general, this parameter falls within the range of 85–95 % [12, 21]. Previous studies have considered values of 90 % in the case of capture with post-combustion [21, 22], and 91.4, 92, 95 % in the oxy-fuel configuration [16, 21]. Still, since no large scale plants exist of none of these technologies for the moment, the same value has been considered for both technologies, 90 %.

First line of Table 4 presents the ratio of avoided CO₂ emissions per unit fuel. Oxy-fuel combustion takes better advantage of every fuel unit for capturing every ton of CO₂ from the process.

CO₂ capture evaluation in the case B SAGD configuration

Table 3 collects the main energy-related parameters of including CO₂ capture into the reference case B of a SAGD

Fig. 7 Summary of CO₂ emissions evaluation in terms of avoided CO₂ for case A

plant. It includes both the total power produced in the GT and the power exported to the grid. The steam required by the process is entirely generated in the HRSG.

The result of GT power output is the consequence of the steam demand in the plant, since the whole thermal power must be produced in the HRSG. There is always surplus electricity, which is exported to the grid.

Regarding the CO₂ capture with post-combustion, the steam requirements of the process turns out considerably higher (56 %), compared to the reference case. This leads to 75 % extra electricity generation and available to the grid. The increase on the fuel in the gas turbine produces higher CO₂ emissions and thus, the steam demand for the solvent regeneration needs up to 15.6 kg/s.

For the oxy-fuel case, however, the energy demanded by the ASU translates into reducing the electricity sold to the grid. The slight difference between with the reference case GT output resides on the variations on exhaust gas flow rate, due to the different composition in oxy-firing operation (consisting mainly of CO₂ and steam). This difference avoids the emission of 0.12 kg/s of CO₂.

Table 3 Main results of integrating CO₂ capture into the reference case B of SAGD process

Cases	SAGD no capture	SAGD with post-combustion	SAGD with oxy-fuel
W_{GT} (MW)	39.80	62.03	39.00
W_{grid} (MW)	25.45	44.62	16.45
Q_{steam} (MW)	60.80	94.75	60.80
Ratio W/Q_{fuel}	0.34	0.34	0.34
m_{fuel} (m ³ N/s)	3.08	4.80	3.02
m_{CO_2} (kg/s)	6.05	0.94	0.59

Table 4 Avoided CO₂ per fuel input SAGD case A and B

	SAGD no capture	SAGD with post-combustion	SAGD with oxy-fuel
Case A	0	1.06	1.80
Case B	0	1.32	1.60

Because of the initial consideration of producing all steam needed with the turbine's exhaust gasses, the W/Q ratio coincides obviously with the gas turbine efficiency in every case.

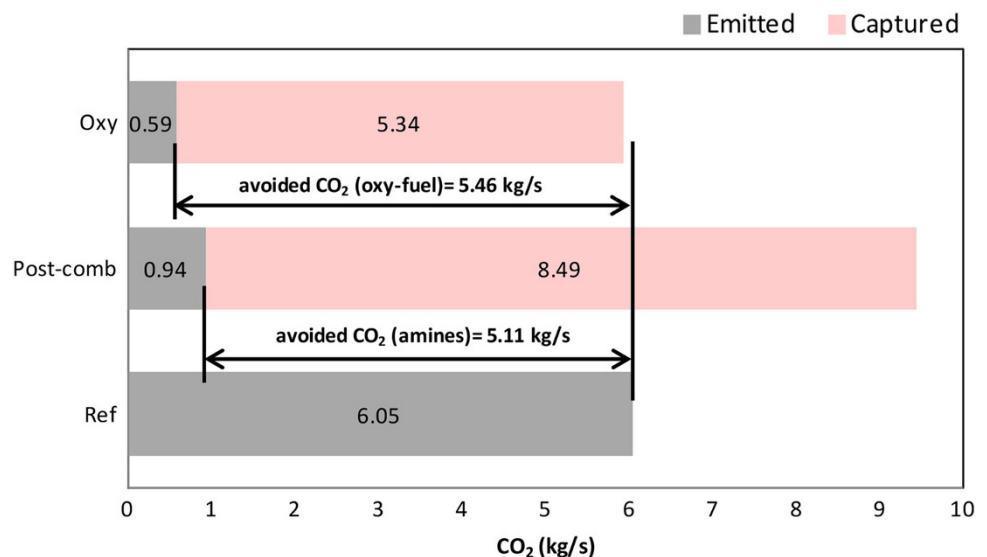
Figure 8 represents the performance of the three configurations in terms of CO₂ emissions. The CO₂ emissions from the post-combustion option are 56 % higher than the reference case B. This means that every unit of avoided CO₂ is more costly in terms of fuel than in oxy-fuel combustion, as expressed in second row of Table 4.

Although the post-combustion configuration appears at first sight as an unfavorable option for this case B configuration, it requires a further data treatment with the corresponding economical assessment, taking into consideration the great amount of electricity that is available in this option.

Conclusions

This work has quantified the influence of integrating a CO₂ capture system into two different layouts of a SAGD plant for in situ bitumen extraction, with and without excess of electricity generation. The CO₂ capture technologies considered included post-combustion capture with amine scrubbing and oxy-fuel combustion.

Fig. 8 Summary of CO₂ emissions evaluation in terms of avoided CO₂ for case B



According to the calculations, oxy-fuel combustion arises as a convenient option in terms of energy efficiency when integrated into the reference case A (generation the electricity needed in the plant). The fuel consumption increase is 9 %, whereas post-combustion absorption requires 29 % more natural gas than the reference case. The reduction of CO₂ compared to the reference plant resulted in 87 and 89 %, for post-combustion and oxy-fuel combustion, respectively.

In the basis of the reference case B (generating all the steam required from the gas turbine exhaust gasses and exporting the electricity excess to the grid), oxy-fuel combustion needs no fuel increase, by sacrificing part of the electricity sold to the grid. This is a clear advantage in terms of fuel savings. Post-combustion CO₂ capture would need increasing natural gas feeding up to 56 %, although in this case, it would be possible to sell 75 % more electricity to the grid.

In terms of CO₂, the post-combustion case would emit 0.94 versus 6.05 kg/s in the reference case. Thus, the avoided CO₂ per unit fuel is 41 % lower than in the oxy-fuel case.

Although the energy analysis pointed out the oxy-fuel combustion as the preferable configuration for CO₂ capture in both configurations, there are still several criteria that should be taken into account to advance a final decision:

- The technology availability is not comparable in both CO₂ capture technologies. Amine-based chemical absorption is a comprehended and experienced technology, applied within other industries aims. Thus, the evaluation of capital and maintenance costs involves larger uncertainties in oxy-fuel combustion case.
- The desirable purity of CO₂ to be compressed, transported and stored is still under research and it strongly depends on the storage site type, and the CO₂ capture technology. If strict CO₂ purity would be needed, additional purification unit would be required downstream the oxy-fuel combustion plant.

Still, these results greatly differ from those obtained in the last decades, when assessing CO₂ capture in fossil fuel power generation systems, in which the energy penalty inferred in the plant efficiency ranges within similar limits, for the different CO₂ capture technologies.

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